IURC Data Request

Energy Policy Act of 2005: Suggested Standards for State Consideration

<u>I. Fuel Sources</u>

Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (12)—Fuel Sources
"Each electric utility shall develop a plan to minimize dependence on 1 fuel source and to ensure that the electric energy it sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies."

1) Do the Indiana Integrated Resource Plan and Certificate of Need processes provide for a sufficient method to insure that utilities develop a plan to minimize dependence on one fuel source? Please explain.

   Yes. Before a regulated public utility can construct a generating facility, it must obtain Commission approval. As the Commission considers a petition for authority to construct a generating facility, it evaluates various methods for providing service, including power purchases, conservation, cogeneration and renewable energy sources. Ind. Code §8-1-8.5-4. Moreover, the utility's proposed project must be found to be consistent with the Commission's Plan for expansion of generating capacity in Indiana. IC 8-1-8.5-5(b)(1). The Commission's Plan with respect to the long-range needs for expansion of generation facilities includes a comprehensive analysis of load growth, reserves, the "optimal extent, size, mix, and general location" of new plants, and the comparative costs of the various means of meeting future electric requirements. IC 8-1-8.5-3. Thus, apart from reviewing every proposed generation project in terms of considering other available options to serve customers, the Commission, on an ongoing basis, analyzes the mix of fuel sources used to serve customers. This review is facilitated by the Integrated Resource Plans filed by the utilities.

See 170 IAC 4-7-2. A key component of each utility's IRP is the selection of a "mix of resources" used to serve customers. 170 IAC 4-7-8. As part of the selection process, the utility must demonstrate that it utilizes, to the extent practical, renewable resources. As a result, the IRP establishes a planning process where fuel mix, including renewables, is considered and modeled as the utility creates its resource plan. In addition, as noted in the IURC Staff White Paper, the IRP rules implicitly require utilities to contemplate the effects of dependence on a single fuel source by considering possible future environmental laws, federal and state energy policies, and swings in fuel prices in the development of their integrated resource plans**.**

It should also be noted that in Indiana, a utility is eligible to obtain financial incentives when it develops renewable energy resources. Ind. Code §8-1-8.8-11 puts clean coal projects and renewable energy projects on equal footing by making both eligible for timely cost recovery, enhanced returns on investment and other incentives.

2) How could the IURC best ensure that the electric energy sold to consumers is generated using a diverse range of fuels and technologies, including renewable technologies?

The concept of fuel diversity is probably best assessed on a regional basis rather than an individual utility basis. An individual utility's reliance on predominantly one fuel source may be an appropriate complement to the fuel mix within a region. The IRP rules appropriately require the incorporation of regional impacts on individual utility resource plans.

IPL participates in the MISO's Energy Market, which is cleared using security constrained economic dispatch ("SCED") computer programs to meet the market's demand and energy requirements across the MISO footprint. Electric energy sold in real time to consumers should represent the lowest dispatch cost resources available subject to the various dispatch constraints of the technologies available in the resource portfolio. Non-dispatchable resources like wind, run-of-river hydro, and solar, will generate based on the wind, water, and sun conditions at the time. Dispatchable resources fueled by coal, uranium, gas, and oil should be dispatched to minimize cost to customers. The resulting fuel diversity will be a function of the amount of load that needs to be served and the portfolio of supply resources available to meet that load across the MISO footprint.

3) Is the requirement of IC 8-1-2-42(d)(1) compatible with a requirement to ensure the electric energy a utility sells to consumers is generated using a diverse range of fuels and technologies, including renewable technologies? Would summary FAC proceedings provide for timely review if such a requirement were implemented? Please explain.

IC 8-1-2-42 (d)(1) should be interpreted in a manner that recognizes that diversity of fuel may be prudent in mitigating potential volatility in the cost of a specific fuel at any given time, and therefore provides customers with energy at the lowest cost reasonably possible. The Commission has already interpreted IC 8-1-2-42(g)(3)(A) in a manner that allows gas utilities to engage in hedging strategies to mitigate price volatility even though, in a given time period, they may procure supply at a cost above current market prices. The FAC cost reasonableness standard should encompass evaluation of reliability and price volatility – if the standard is so applied, then fuel diversity can be appropriately accommodated. In accommodating the portfolio approach, the Commission should allow each utility the flexibility to create the resource mix that fits its size, location, and existing resource profile. An arbitrary requirement for integration of a specific type of fuel or generating method that ignores transmission congestion, lack of renewable resources in its geographic area, current nature of a utility's investment in resources, and its flexibility given its load size, would be potentially detrimental to customers from a cost perspective, and would negate the planning efforts and expertise that exist today. The IRP and certificate of necessity processes provide the opportunity for the Commission to engage in processes with each utility to create an appropriate fuel mix for that utility. Those processes are superior from a planning perspective compared to use of summary FAC proceedings as a planning mechanism. Further, the IRP and certificate processes allow the Commission to make determinations regarding the balance of cost and fuel diversity considerations in light of the comprehensive analytic review the Commission engages in to create its Plan for meeting customer demand in Indiana.

4) Does today's energy market environment provide sufficient incentive for utilities to diversify their fuel sources? Please explain.

Yes. The development of the Day Two energy market provides incentives to invest in infrastructure that will improve the ability to move energy across the bulk transmission system. To the extent this provides an incentive to invest in renewable energy resources due to increased access to the transmission grid, Day Two does support fuel diversity. In addition, sources of green power may be more accessible to load serving entities via an improved transmission grid. Day

Two does not change the pre-Day Two desire of generators to have low cost energy available to sell in the marketplace.

II. Fossil Fuel Generation Efficiency

Amendments to PURPA; Sec. 1251; amending 16 USC 2621(d) by adding (13)— Fossil Fuel Generation Efficiency

1) What, if any, specific plans has your utility put in place to drive increased fossil fuel generation efficiency? How do these plans differ from what was done in the past? How do you expect these plans to change over the next ten years?

   Indianapolis Power & Light Company (IPL) has historically maintained fossil fuel generation efficiency by repairing or performing routine maintenance on equipment. Typical examples of routine maintenance are provided below:

   a. Steam Turbine Overhaul
   b. Boiler Tuning
   c. Boiler Tube Replacement
   d. Performance Testing
   e. Boiler Feed Pump Turbine Overhaul
   f. Pump Overhaul
   g. Cooling Tower Repair
   h. Condenser Tube Cleaning
   i. Condenser Tube Replacement
   j. Boiler Draft Fans Inspection and Maintenance
   k. Coal Mill Maintenance and Overhaul
   l. Air Heater Basket Replacement
   m. Combustion Air Heater Coil Replacements
   n. Feedwater Heater Re-tube / Replacement

   Major efficiency improvement projects are periodically performed as technological advancements and economic justification warrant. These efficiency improvements did not result in a net increase of emissions. These projects benefit all IPL stakeholders. Some of the past improvements include:

- Petersburg Unit 1 Soot Blowing Controls
- Petersburg Unit 2 Turbine Steam Path Upgrade – Dense Pack
- Petersburg Unit 2 On-Line Remote Monitoring
- Petersburg Unit 2 Soot Blowing Controls
- Petersburg Unit 3 Turbine Steam Path Upgrade – Dense Pack
- Petersburg Unit 3 ID Fan Variable Frequency Drives
- Petersburg Unit 3 Cooling Tower Replacement
- Petersburg Unit 3 Soot Blowing Controls
- Petersburg Unit 4 Turbine Steam Path Upgrade – Advanced Design Steam Path
- Petersburg Unit 4 On-Line Remote Monitoring
- Petersburg Unit 4 Soot Blowing Controls
- Harding Street Unit 5 ID Fan Variable Frequency Drive
- Harding Street Unit 6 ID Fan Variable Frequency Drive
- Harding Street Unit 7 Turbine Steam Path Upgrade – Advanced Design Steam Path
- Harding Street Unit 7 ID Fan Variable Frequency Drives
- Eagle Valley Unit 4 Turbine HP Rotor Replacement
- Eagle Valley Unit 5 Turbine HP Rotor Replacement
- Eagle Valley Unit 6 Turbine LP Rotor Replacement
- Eagle Valley Unit 6 Condenser Back-flush System
- Performance Data Acquisition Systems on all Coal-fired Units
- Boiler Distributive Combustion Control Systems on all Coal-fired Units

IPL has installed pollution control equipment that has generally reduced the overall plant efficiency including the following:

- Petersburg Unit 1 Low NOx Burners
- Petersburg Unit 1 Neural Network
- Petersburg Units 1&2 Fluidized Gas Desulfurization System
- Petersburg Unit 2 Low NOx Burners
- Petersburg Unit 2 Selective Catalytic Reduction System
- Petersburg Unit 3 Selective Catalytic Reduction System
- Petersburg Unit 3 Fluidized Gas Desulfurization System Modification
- Petersburg Unit 4 Low NOx Burners
- Petersburg Unit 4 Neural Network
- Harding Street Unit 5 Low NOx Burners
- Harding Street Unit 5 Neural Network
- Harding Street Unit 5 Selective Non-Catalytic Reduction System
- Harding Street Unit 5 SO3 Injection System
- Harding Street Unit 5 Electrostatic Precipitator Upgrade

- Harding Street Unit 6 Low NOx Burners
- Harding Street Unit 6 Neural Network
- Harding Street Unit 6 Selective Non-Catalytic Reduction System
- Harding Street Unit 6 SO3 Injection System
- Harding Street Unit 6 Electrostatic Precipitator Upgrade
- Harding Street Unit 7 Low NOx Burners
- Harding Street Unit 7 Neural Network
- Harding Street Unit 7 Selective Catalytic Reduction System
- Harding Street Unit 7 Electrostatic Precipitator Upgrade
- Eagle Valley Unit 3 SO3 Injection System
- Eagle Valley Unit 4 Low NOx Burners
- Eagle Valley Unit 4 SO3 Injection System
- Eagle Valley Unit 5 Low NOx Burners
- Eagle Valley Unit 5 SO3 Injection System
- Eagle Valley Unit 6 Low NOx Burners
- Eagle Valley Unit 6 Neural Network
- Eagle Valley Unit 6 Electrostatic Precipitator Replacement

IPL has developed a comprehensive plan to meet current environmental standards in a cost effective and reliable manner. The ability to increase the efficiency of IPL's low cost coal-fired generation is complicated by attempting at the same time to comply with ever-changing state and federal environmental regulations and with the uncertainties surrounding New Source Review Requirements. At this time, IPL is considering the following plant improvements:

- Petersburg Unit 1 Turbine Steam Path Upgrade
- Petersburg Unit 2 Sodium Bisulfate System
- Petersburg Unit 3 Sodium Bisulfate System
- Petersburg Unit 4 Fluidized Gas Desulfurization System Modification
- Harding Street Units 5&6 Fluidized Gas Desulfurization System
- Harding Street Unit 7 Fluidized Gas Desulfurization System
- Harding Street Unit 7 Sodium Bisulfate System
- Eagle Valley Unit 4 Electrostatic Precipitator Upgrade
- Eagle Valley Unit 5 Electrostatic Precipitator Upgrade
- Mercury Controls

In addition to IPL's internal activities to improve fossil fuel generation efficiency, the experience and knowledge of personnel in other AES businesses is a valuable resource. The AES North America Operating Network is a good example of how information is exchanged within a global power company. Several working groups comprised of technical people across North America are developing and reviewing best practices to improve outage management, work management, root cause analysis, operational risk assessment, and training and qualifications. All of which are directed toward improvements including fossil generation efficiency.

2) Does today's energy market environment provide sufficient incentive for utilities to increase the efficiency of its fossil fuel generation? Please explain.

Yes. The MISO Day-2 Energy market payments to generators are based on the marginal cost of the last generating unit to clear the market. This provides a strong incentive for generators to improve efficiency in that any efficiency gains translate directly into improved margins for all units that clear the market. In addition, generators are competing against each other to become the marginal unit. This competition should also provide an incentive for these marginal units to become more efficient.

3) Provide the historical annual operating efficiencies for the past 10 years for each of your fossil fuel generation plants and a similar cumulative value for your utility.

The following table shows the "heat rate" for IPL's coal-fired plants, both individually and cumulatively for the past 10 years. Net Heat Rate = the total heat content consumed by the coal-fired units in decatherms (1 million BTU's) divided by the net generation of each coal-fired unit. Net generation is defined as the gross output of the unit less the auxiliary power consumed by the power plant. It is the quantity of power that is delivered to the switchyard/transmission system.

	Petersburg Total Coal-fired	Harding Street Total Coal-fired	Eagle Valley Total Coal-fired	Total IPL Coal-fired
Year ended				
1995	10,374	10,491	11,553	10,456
1996	10,477	10,470	11,269	10,515
1997	10,564	10,414	11,470	10,595
1998	10,502	10,315	11,621	10,537
1999	10,630	10,316	11,679	10,639
2000	10,585	10,159	11,736	10,597
2001	10,382	9,985	11,742	10,399
2002	10,369	9,976	11,805	10,397
2003	10,467	9,998	11,685	10,461
2004	10,467	10,246	11,679	10,515
2005	10,495	10,452	11,729	10,595

III. Smart Metering

Amendments to PURPA; SEC. 1252. Amending 16 U.S.C. 2621(d)) by adding:
(14) Time-based Metering and Communications.—

(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.
(B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others—
(i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;
(ii) critical peak pricing whereby time-of-use prices are in effect except for certain

peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;
(iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and
(iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.
(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.
(D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.
(E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.
(F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C)

1) Please describe the present status of time-based metering and communications within your customer base. Include detail by customer class (e.g. residential, commercial, industrial) relating to tariff offerings, smart meters deployed, means of communicating collected data with participating customers, and capital invested in infrastructure.

   IPL has deployed survey meters for load research purposes among the Residential and Small C&I customer classes. The load research data collection for these classes is accomplished via hand-held probe devices. IPL's Large C&I customer class is demand metered, with fifteen-minute interval data collected on a monthly basis using hand-held probe devices.

   <u>Residential Class</u>

   <u>Tariff Offerings</u> – there are no time-based tariff offerings for this class.

Smart Meters Deployed – While IPL does not have any "Smart Meters" as defined by the Commission Staff in the White Paper dated April 2006; IPL has extensively deployed Automated Meter Reading (AMR) equipment for all customers that are billed on an energy only basis (customers in the Residential and Small C&I classes). At present, these meters only collect energy consumption data on a monthly basis for billing purposes. However, with additional infrastructure investment, many of these meters may be able to be configured for two-way communication.

Communication – IPL communicates with the energy only meters using an AMR "Cellnet" system. IPL's energy only meters wirelessly relay information to over 1,500 Micro-Cell Controllers deployed throughout IPL's service territory. These Micro-Cell Controllers then pass the gathered data along to 18 Cell-Master devices using licensed radio frequencies.

Capital Investment – The Cellnet system is owned by IPL's vendor. IPL pays the vendor for each meter read made on our behalf.

Small Commercial & Industrial Class

Tariff Offerings – there are no time-based tariff offerings for this class.

Smart Meters Deployed – Meters in the Small Commercial & Industrial Class are all energy only meters; therefore, the statements above for the Residential Class describe our metering capabilities for the Small Commercial & Industrial Class.

Communication – IPL communicates with the energy only meters using an AMR "Cellnet" system. IPL's energy only meters wirelessly relay information to over 1,500 Micro-Cell Controllers deployed throughout IPL's service territory. These

Micro-Cell Controllers then pass the gathered data along to 18 Cell-Master devices using licensed radio frequencies.

Capital Investment – The Cellnet system is owned by IPL's vendor. IPL pays the vendor for each meter read made on our behalf.

Large Commercial & Industrial Class

Tariff Offerings – IPL currently offers one time-based tariff, Standard Contract Rider No. 8 – Offpeak Service. This Rider provides for a reduced demand charge for billing demand established during off-peak hours, which are defined as the weekday hours between 10 p.m. and 6 a.m. and all weekend hours.

Smart Meters Deployed – Large C&I customers do not currently receive electricity consumption information on a real-time basis. IPL does not have the ability to provide that service with our existing metering infrastructure.

Communication – Data retrieval is accomplished by a monthly visit to the customer's metering equipment, at which time the data is downloaded into a hand-held probe device by IPL personnel.

Capital Investment –The approximate cost to provide the demand metering equipment on a per point basis is $1,400.

2) Describe the methods utilized presently or historically to communicate tariff/program opportunities to customers. Do you have plans to enhance marketing of these opportunities? Please explain.

For Large C&I customers, the communication channel is the account management team.

For Residential customers, the communication channel is direct mail, bill messaging, bill inserts, and web-based information, as well as our customer service representatives.

As new programs and opportunities are developed, marketing strategies will be designed to fit the specifics of the program characteristics.

3) Detail any cost/benefit studies conducted for your service area regarding time-based metering communication deployment and tariffs. Detail should at a minimum include cost and demand response assumptions.

IPL commissioned a Critical Peak Pricing evaluation, which was completed in late 2004 by Christensen Associates. A PDF copy of this study is included as part of the Data Request response.

4) Detail the response to any customer surveys you may have conducted in your service area regarding time-based metering and rates. If no surveys have been conducted, what customer input method does your utility employ to evaluate customer demand for time-based metering and rate offerings?

IPL has not conducted any customer surveys regarding time-based metering and rates.

Customer Input method—To this point, IPL has relied upon customer information that is in the public domain that has either been compiled by other utilities or by consultants in the field.

5) What, if any, regulatory barriers exist which limit the expansion of time-based metering and rates?

Implementation of time-of-use and real-time pricing would require significant capital investments. Utilities must be given the opportunity to recover all reasonable program costs and lost revenues.

6) Can time-of-use rates be effectively implemented without the use of smart metering? Please describe any new or expansion of existing time-of-use rates your utility plans to implement in the next 24 months.

If seasonal rates were defined as a type of time-of-use rate, then, yes, this type of TOU rate could be effectively implemented without the use of smart metering.

IPL is not aware of any other type of TOU rate that could be effectively implemented without the use of smart metering.

IPL has no specific plans in place for implementation of TOU rates within the next 24 months; however, TOU will continue to be included among the universe of offerings that IPL may consider in the future.

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INDIANA UTILITY REGULATORY COMMISSION
ELECTRICITY DIVISION

CHRISTENSEN
ASSOCIATES

Economic Analysis and Consulting

An Evaluation of the Potential for Critical Peak Pricing

at

Indianapolis Power & Light Company

by

Laurits R. Christensen Associates, Inc.

December 17, 2004

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costs range from $400 to $1,500, depending on system capabilities and upon the presence of interval metering.

Gulf Power's "high-end" system delivers load reductions in critical peak hours on the order of 50 percent of customers' load during peak periods, while the "low-end" California pilots generate response in the range of 10 to 20 percent. Since larger residential customers tend to join, a 50 percent reduction translates into roughly 2kW per site. Gulf Power hopes to sign up 40,000 of 400,000 residential customers and have at its disposal a resulting 80 MW of load relief.

Factors Affecting Program Viability

We identified four factors affecting program viability at IPL: 1) enough customers with sufficient responsiveness to yield adequate load impacts; 2) customer willingness to participate; 3) ability of IPL to cover program costs; and 4) sufficiently high and variable wholesale prices to offer opportunities for load response. IPL has approximately 400,000 customers, similar to Gulf's customer population, with apparently sufficient penetration of air conditioning and electric heating service to offer adequate response capabilities.

Program cost recovery can be approached in a number of ways besides full recovery from participants. First, interval metering is spreading among smaller customers. It is an issue as to whether the full cost should be imposed on participants or spread to all the utility's customers. Second, the provider has some choice as to how sophisticated the system should be. However cost recovery is approached, the expenses are large: at $400 per account, a program of 40,000 customers yielding perhaps 80 MW of load relief would cost $16 million in equipment costs.

High wholesale prices are likely to be the primary trigger for CP calls at IPL, as transmission constraints do not often threaten. Locally, short-notice distribution problems might be alleviated via selective CP activity. For the past three to four years, the region around IPL has been characterized by ample reserves and low wholesale prices. In our opinion this is likely to continue for a few years to come, although reserve margins will tighten slowly and steadily. That said, extreme weather or unanticipated outages can alter this picture to some degree.

Analysis of Net Benefits of CPP

To bring these considerations into focus, we undertook a high-level quantitative analysis of the net benefits of CPP service. We used a simplified CPP product in which retail price is equal to expected wholesale price for all pricing periods, including CP periods. We investigated four different marginal cost levels, each based on ECAR wholesale price history from 1997 to 2004.

Table ES1 summarizes the results of this analysis. Wholesale prices increase from left to right across the table columns, as do the number of hours of CP calls and the CP price. The per-customer results appear in the top of the table while aggregate results for 40,000 customers appear in the lower half. Only when prices become very high and CP calls become frequent do benefits turn positive. We include one additional possible source of benefits in the computation, avoided capacity costs that may have been missed by the wholesale prices as they are currently computed. While theoretically all reliability costs

1. Introduction

Retail providers of electricity have recently been exploring retail pricing products that reflect wholesale market conditions and marginal cost to a greater extent than have traditional tariffs. Reasons for this trend include the collapse of the California retail market and the extensive blackouts that ensued, the development of transparent wholesale energy markets and prices and regional ISO/RTOs in certain parts of the country, and the resulting perceived need for price-responsive demand to improve the functioning of the wholesale market. This interest is not confined to states where such markets have emerged, as products that can help to reduce peak period costs are generally of interest. The awareness of marginal cost and wholesale price volatility and the potential savings from reducing usage in peak price hours have induced utilities to investigate various types of short-notice "dynamic pricing" products that yield demand response by customers.

Large customers have had access to demand response programs, such as real-time pricing and interruptible service, for some time but small customers have seen few such programs. Typically, this is due to the assumptions that dynamic pricing is costly to provide and would be unlikely to produce a large enough response to make it worthwhile. Lately that perspective has been challenged by the critical peak pricing (CPP) concept. Reflecting this trend, IPL is exploring the potential of CPP to provide benefits to its customers and to the company.

In reviewing the capabilities of the CPP structure, it is important also to review the technology bundled with the product. CPP requires the introduction of advanced metering at the mass market customer level. Additionally, current providers have been experimenting with communication and control technology to try to enhance response. The key issues for CPP are what combination of product structure and technology will attract enough customers and induce enough response in critical peak periods to yield the most benefits and whether those benefits will be sufficient to justify CPP service. The purpose of this report is to provide IPL with an objective assessment of the potential appropriateness and cost effectiveness of a CPP program.

The next section of this report provides a description of CPP, including its structure, price development, and technological support requirements. Section 3 reviews existing CPP programs. It provides details on how CPP is actually offered and presents the results to date on how customers respond to the product. Section 4 provides a description of the factors affecting the cost effectiveness of CPP for IPL. Section 5 offers a high-level assessment of the benefits of CPP under alternative marginal cost scenarios. The report concludes with a summary and recommendation.

2. The CPP Product—Concept and Design

2.1 Structure and Pricing

CPP provides customers with standard tariff pricing except in a few "critical peak" hours when customers receive a price signal reflecting conditions of very low reserves or very high wholesale market prices. CPP is most often packaged with a standard voluntary TOU tariff, so that the customer faces TOU pricing periods. The CPP price signal either is constrained to occur in the on-peak period or tends to occur there predominantly.

traditional TOU because utilities have combined short-notice pricing with enabling technology that facilitates customer response through automated response systems.

2.3 Technical Support Requirements

The technology requirements associated with offering CPP service can be substantial, depending upon the degree of automated signaling and customer control that is desired. A fundamental need is interval metering equipment, with either manual reading or advanced automated systems for polling meters from a central site. In addition, some means is needed to communicate critical price signals to consumers. Finally, many CPP programs include automated control technology at the customer site to provide "hands-off" control of certain major energy-using devices such as air conditioning systems. These systems are particularly important for short-notice programs that provide as little as an hour's notice of critical price initiation. Evidence from previous studies also indicates that consumers' price response tends to be substantially greater in the presence of automated control equipment.

Price Signaling: Some CPP programs use email or automated telephone messaging to alert customers to CP periods, especially if notice is on a day-ahead basis. However, for shorter notice, providers use direct signals to automated control devices.

Automated Control: Control devices vary considerably in capabilities. A basic unit can be a smart thermostat, with temperatures programmed for certain times by the customer, plus an override for the critical peak signal. Such units control heating and cooling. More advanced units permit tie-ins to other end uses, including water heaters and pool pumps. Washers, electric dryers, and dishwashers are also candidates, although they do not seem to be accessed by the programs that we investigated. A new wrinkle in control is the use of web sites to permit customers to control conditions and override control from a remote location.

Data Recording: As noted above, advanced metering is necessary, along with the back-room capability to manage the large increase in data and to bill the customer.

2.4 Program Cost Recovery

Taken together, these support requirements involve substantial incremental costs to serve each customer. Without counting other program development costs, the material and installation costs of this support equipment can amount to as much as $1,500 per site. For small customers with bills on the order of, say, $700–$1,200 per year, this implies a lengthy payoff period, should they be required to shoulder all the costs of outfitting. The prospective provider of CPP does have some degree of choice in expense level. The above price is for a "high-end" system that enables control of several uses. A program that confines itself to a single end use, such as air conditioning, might well reduce these costs significantly.

A key issue regarding metering costs is the extent to which the metering equipment is considered an incremental cost to the CPP program. A number of utilities are assessing the business case for installing advanced metering systems for the mass market, on the basis of operational cost savings and revenue enhancement, even without considering the additional potential benefits from dynamic pricing. For example, IPL's decision to install advanced meters for cost efficiency reasons means that their cost should not be counted against a CPP program, unless additional capabilities such as retrieval of hourly data are required.

Table 1
CPP Program Participation

	Gulf - RSVP	Dairyland	Ameren	California - SPP
Current	6,400	-	225	1,654
Target	40,000	small		
Customers	residential	residential	residential	residential and small commercial
Segments			three groups: conventional TOU, CPP w/o technology,CPP w/ technology	three utilities, three products, three customer types (avg, low income, already DR participants)

Table 2
CPP Program Structure and Pricing

	Gulf - RSVP	Dairyland	Ameren	California - SPP
TOU tiers, seasons	3 tiers, nonseasonal, but peak period seasonal	3 tiers, nonseasonal, but peak period seasonal	3 tiers, seasonal	2 tiers, seasonal
Product alternatives			traditional TOU, CPP	CPP-F: fixed time period; CPP-V: variable time period
Revenue Neutrality	annually	possibly not	by season as well as annually	approximately over year but not seasonally
Cost Recovery	cust chg: $4.95, energy charge: $2/month; environmental surcharge on rate base	customer chg: $10; others possible	no incremental charges; incentive: $25 to join, $75 after 6 mo.	no incremental charges; incentives to participate up to $175
On-peak to off-peak price ratio	2:1	3:1	3:1	two forms: 3:1 and 2:1
Critical peak price	31¢	33¢	30¢	71¢ (3:1 ratio), 51¢ (2:1)
CP period	no restriction by time of day, calls in winter and summer	no restriction by time of day	3-7 pm, summers	5 hours, 2-7pm summer weekdays
CP criteria	differs by season; some combination of RTP price, weather, system conditions	to be determined	extreme weather	weather, system reliability conditions
CP notification	half-hour-ahead	hour-ahead	day-ahead	CPP-F: day-ahead; CPP-V: same-day

hour CP period coterminous with the on-peak period. In contrast, the CPP-Variable product provides same-day notice and is meant for those who prefer a shorter peak period if possible: the CP period can be two to five hours long, all within the on-peak period. (The price does not vary even if the period is shorter. This slight diminution in accuracy of pricing is compensated for by the simplification in the product structure.)

3.3 Technology Support for Current Programs

Some diversity is evident in the technology adopted to support these programs. All use advanced metering but different approaches emerge with respect to price signaling, control technology and the end uses controlled. Table 3 provides a summary.

Table 3
CPP Program Technologies

	Gulf - RSVP	Dairyland	Ameren	California - SPP
Price Signaling	VHF paging	VHF paging	automated calling plus message to smart thermostats	automated calling plus pager; some customers already had smart thermostats; additional automated signaling in 2004
Automated Control Provider	Comverge	Comverge	Cannon Technologies	Invensys
Control Unit	Gateway	Gateway	Cannon Honeywell ExpressStat	Goodwatts
Control Override	on-site override; remote override via internet in prospect	on-site override	call to AmerenUE call center or via hardware provider's web site	on-site override and web-based control
End Uses Controlled Directly	HVAC, water heater, pool pumps	HVAC, water heaters	HVAC	AC; more recently pool pumps and water heaters

Although there are four programs in the table, the Dairyland strategy is very similar to that of Gulf Power, as Dairyland has adopted the Good Cents Select approach. This involves a more intensive control strategy than the other programs, as it has the capability to control more end uses than just the HVAC systems. Additionally, the Comverge control device has the pricing programmed into the product, making it somewhat more expandable than the smart thermostat, which controls via a temperature control only, supplemented by the CP signal and customer overrides.

The California SPP program is interesting because it adopted a somewhat "low tech" approach to CPP, with automated telephone calls and pagers being used to notify customers and no direct load control unless such capability had previously been put in place. Their 2004 experiment has since offered some control technology to some customers. The technology involves smart thermostats, supplemented by pool pump and water heater controls, similar to the Gulf end-use mix. Analysis of the impact of this technology on response is due in December on the CEC website. Additionally, some customers are apparently making use of Invensys climate controls. Their Goodwatts system appears to be similar to that of the Comverge Gateway. One apparent difference is the use of power line times, reserves are as low as 5 percent, a CPP-induced 80 MW reduction would significantly improve reserves.

CPP customers also appear to reduce *overall* consumption modestly. For example, the GPU study found a summer season load reduction of about 5 percent. Gulf Power experienced a similar decline of about 4 percent in the first year of its pilot.

The evaluation of the California SPP programs turned up other results that may be instructive for IPL.[3] First, in that program, large customers appeared more price responsive than smaller users. In percentage terms, the CP period reductions were about 17 and 10 percent respectively. Second, high-income households were 25 percent more responsive than low-income, other things being equal.

Econometric Analysis: The few studies of customer response to CPP indicate that customers do respond to price changes, and respond more strongly than do customers on traditional TOU pricing. Additionally, there appears to be some tendency to reduce consumption, or to grow more slowly than comparable customers, at least in the first year of CPP service. To the extent that this overall reduction is expected, IPL may want to take it into account in designing the prices under the program to avoid net revenue reductions.

The measure of consumers' propensity to shift consumption from one period to another in response to relative price changes is called the elasticity of substitution (ES). It is defined, for purposes of the analyses reported here, as the (negative of the) ratio of the percentage change in the peak to off-peak consumption resulting from a one percent change in peak to off-peak prices. The analysis of GPU's CPP customers by Braithwait found an ES of about .30. That is, a one-hundred percent increase in the peak to off-peak price ratio will produce a 30 percent reduction in the ratio of peak to off-peak consumption. For the sake of comparison, ES values in traditional TOU programs have been estimated to range from 0.13 to 0.17.

The GPU experiment included interactive communication equipment which controlled the home thermostat and had the ability to interrupt various circuits in the home. The program featured a 50¢ CP price and two TOU alternatives, one with an on-peak to off-peak price ratio of 2.8, the other of 4.6. Peak prices were 25 and 30¢ respectively. Thus, the higher CPP prices relative to standard TOU values, plus the automated control boosted load shifting by customers by almost a factor of two. The control equipment used at GPU was a predecessor of the gateway technologies used currently by Gulf Power.

The California SPP program produced more modest ES estimates. The researchers found a statewide average value of approximately 0.08; with the moderate climate zones recording values of 0.04 to 0.06 and the more extreme climate zones registering 0.11 to 0.16. These lower ES values may be explained in part by the fact that most customers were not provided with automated control equipment.

[3] Faruqui, A. and S. George, California Experiments with Dynamic Pricing, Aug. 4, 2004.

4.2 Program Participation

One purpose of a pilot program at IPL would be to test directly customers' willingness to participate in a CPP program. There is relatively little evidence available at present from other programs, as they are all pilots at this stage, with the exception of Gulf Power's RSVP program. As mentioned previously, Gulf's program is "ramping up" from pilot numbers to a target of 40,000 customers, about 10 percent of the customer population there. Gulf Power's customers have experienced higher retail prices than those of IPL and may thus be more energy-aware than those in IPL's service territory. Thus, it is uncertain whether IPL's customers will be as willing as Gulf's to participate in market price-based programs. It is worth noting again that Gulf's customers pay on average an extra $84 per year in incremental customer and energy charges for the opportunity to save money by managing load. Gulf estimates that these customers still save up to 15 percent on their standard tariff bills. Thus, the utility has found (and expects to continue to attract) customers of sufficient size and flexibility to want to join.

Two sources of additional information are available. First, Electricité de France offers a voluntary "day-type" pricing program that has critical *days* instead of peak periods, with day-ahead notification. On critical days, both the on-peak and off-peak prices are high relative to the other two day-types. (The peak day-type on-peak to off-peak price ratio is just 3:1 but the peak price is roughly five times the medium priced day's peak period price.) While this type of product encourages a somewhat different load shifting pattern (with greater emphasis on shifts across days) its general design and purpose is similar to CPP's. The program requires installation of a signal reception device and an automated control device for electric heating and water heating. This program has attracted thousands of customers.

Second, the California Energy Commission's Working Group 3 has issued reports on Customer Preferences Market Research that investigate customer willingness to participate in CPP and other time dependent programs.[4] This survey revealed that customers on current California inclined block rates would adopt a CPP product at rates of between about 10 and 50 percent, with about 15 to 20 percent being a likely average. This number rises with access to control technology.

4.3 Program Costs

Section 2.4, above, listed briefly the estimated technology installation costs for a CPP program with automated communications and control, supplemented by advanced metering. These costs came to about $1,500 per site, based on Gulf Power's data. Other less technically advanced programs may have been less expensive.

These costs are in addition to conventional program design, marketing, reporting, and ongoing support costs. The Ameren presentation provided by IPL provides some insight with its pilot program cost estimates. These appear to indicate costs, net of technology purchases, of about $300,000 over a two-year period, for a program that recruited 225 participants. Additionally, their cost listing shows no incremental metering expense and does not appear to make provision for any "back office" or overhead cost changes. (The remaining significant item was for focus groups.) This snapshot of program costs appears to

[4] Momentum Market Intelligence, Customer Preference Market Research, A Market Assessment of Time-Differentiated Rates among Residential Customers in California, December, 2003.

In adopting this approach, we have abstracted from IPL's own current residential tariff and from a specific CPP TOU design of the sort described elsewhere in this report. We have done so because the analysis was meant to focus on CPP's general viability rather than the viability of a specific product. This approach has certain implications regarding estimated benefits. First, the assumption that retail commodity prices are set equal to expected marginal cost implies that total societal benefits from load modification due to CPP are maximized. Second, utility net benefits are approximately zero; consumers receive all of the benefits from responding to CP prices. This is not important to the analysis of program viability, as the key viability concern is overall positive net benefits. If positive net benefits do occur, then prices may be designed to diverge from marginal cost in ways that provide some sharing of benefits from load modification between consumers and the provider, with some reduction in overall social benefits in consequence.

Finally, the assumption of a pre-existing TOU structure, to which the CPP alternative is appended, implies that all benefits come from load response to CPP alone; no benefits gained from introducing TOU service relative to the existing residential tariff (or from transfers resulting from self-selection) were calculated. This approach was followed to focus attention on the incremental benefits from CPP.[6]

5.2 Assumptions

If benefits derive from load response only, then the CPP viability question becomes one of determining how frequently CP periods need to be called and how high CP prices have to be to generate benefits that exceed program costs. The analysis thus requires assumptions about marginal cost, customer responsiveness to CP prices based on expected marginal costs, and the magnitude of program costs.

Marginal costs and retail prices: We assumed that the marginal cost of generation is equivalent to the wholesale spot price of energy. While other assumptions have been made in the past (such as internal marginal cost of energy, augmented by some concept of capacity cost) wholesale spot prices for a location near to the service location are coming to be recognized as the best representation of the cost of generation and resource scarcity. (This assertion is qualified, of course, by instances of transmission constraint, which does not appear to be particularly relevant in IPL's case.)

IPL provided us with a history of hourly day-ahead wholesale prices for the ECAR region for the period January 1997 to October 2004. IPL also provided an indication of future costs with a system marginal cost forecast for 2011, along with a capacity cost value. The ECAR wholesale price history contains an initial period of considerable volatility through 2000, followed by several recent years of negligible instances of apparent resource tightness and resulting high market prices. The low prices of 2001-04 are due chiefly to the arrival of new generation supply, supplemented by summers of moderate temperatures. Figure 1 presents this history for the hour ending 4:00 pm.

[6] We note that previous research has generally found that voluntary TOU programs have had difficulty attracting sizable numbers of customers without problems of revenue attrition from self-selection. As a result, conventional voluntary TOU programs tend to offer small benefits. Excluding this preliminary step is unlikely to omit significant benefits for IPL in offering CPP.

In developing scenarios of likely wholesale commodity prices, we used the hourly price profiles of 1997, 2000, and 1999 to represent low-, medium-, and high-cost cases.[7] We then developed four marginal cost scenarios using alternative weightings of these cases. These were intended to represent scenarios of increasingly tight reserves. Under these scenarios, progressively more CP hours were expected to occur, and the expected price climbed with the prices in these hours. Table 5 below shows how the expected number of hours and expected CP price increased across scenarios. The case weights appear at the bottom of the table.

Table 5

Expected Marginal Costs, by Scenario

Scenario	A	B	C	D
Average Expected Energy Costs				
Non-CP peak summer hours	$0.0336	$0.0580	$0.0927	$0.1500
All Peak summer hours	$0.0345	$0.0678	$0.1165	$0.2027
Non-peak hours	$0.0189	$0.0205	$0.0233	$0.0281
Expected MC during CP	$0.3026	$0.4120	$0.5071	$0.6488
Expected CP hours	2	14	29	53
low-medium-high case weights	90/10/0	40/40/20	20/30/50	0/0/100

Based on the historical pattern of prices over the course of summer days, we selected the non-holiday weekday hours from 1:00 pm to 7:00 pm as peak hours. Table 5 also shows how other summer prices trend upward across scenarios. It is clear from the non-CP peak hours that the historical data that support the CP results also involve generally high peak period costs as well.

In computing expected costs during CP periods, we assumed that not all the highest prices would be selected. Practical reasons for this are: 1) failure of the utility to perfectly anticipate when the highest-cost hours will occur, 2) the related restriction that in deciding to call a CP period, the utility does not know whether this will mean that it cannot call later should even higher prices occur, 3) the fact that not all high prices occur in groups of satisfactory length of, say, four hours. We mimicked these limitations by selecting decreasing proportions of hours within each price range.

It should be noted that we are not predicting that any one of these scenarios will *necessarily* occur. They are simply indicators of a broad range of possible market outcomes, based on what has actually happened in the past and might therefore occur again with some degree of likelihood.

Load responsiveness: IPL has in mind a level of control and communication technology close to but not equal to that of Gulf Power's RSVP program, and probably ahead of the California project. Specifically, IPL is contemplating short advance notice of CP hours, on the order of half an hour, and automated control of programmed air conditioning and perhaps

[7] We could have used some of the 2001 to 2004 data but this would not have added to the scenarios of interest when asking the question, "How high do prices need to be to make CPP valuable?"

amount.) Nevertheless, equipment costs are significant. We explore below the implications for program viability of selecting alternative values.

5.3 *Results*

Table 6 presents results for each of the four marginal cost scenarios described above, with expected marginal cost increasing across the table from left to right. The top half of the table provides per-customer estimates and the bottom half provides results for the 40,000 customer program outlined above.

Table 6

Net Benefits of CPP Pricing, by Scenario

Scenario	**A**	**B**	**C**	**D**
Per-Customer Change in Benefits Relative to Base				
Customer bill change (reduction)	$0.73	$7.07	$14.77	$27.50
% of summer base bill	0.2%	1.8%	3.1%	4.3%
Utility net revenues				
Utility costs	-$0.73	-$7.07	-$14.77	-$27.50
Utility revenues	-$0.73	-$7.07	-$14.77	-$27.50
Utility net revenues	$0.00	$0.00	$0.00	$0.00
Total	$0.73	$7.07	$14.77	$27.50
Aggregate Change in Benefits				
Change in Benefits Relative to Base	$29,114	$282,826	$590,906	$1,099,919
Avoided Generation Costs	$701,129	$582,434	$474,689	$375,546
Program Costs (annualized amount)	$1,321,833	$1,321,833	$1,321,833	$1,321,833
Total Net Benefits	-$595,927	-$519,247	-$374,261	$113,454
% of participants' summer base bills	-4.6%	-3.3%	-1.9%	0.4%

Benefits derived from load response to CPP may accrue to both customers and providers. We report changes in revenues and costs for the provider (IPL). We also include an additional benefit to the provider, the value of avoided capacity costs, that is generally passed on through regulated rates to customers via lower rates.

If wholesale prices fully incorporate expected marginal reliability costs, then the sum of expected customer and provider net benefits will capture all available benefits. However, as energy markets are still relatively immature, it is possible that not all reliability benefits are incorporated in the wholesale prices used to analyze CPP. Residual benefits may be estimated by valuing the expected load relief provided by CPP customers and then selecting a portion of these benefits for inclusion in the estimate. We valued load relief at an annualized $38/kW-year (in current dollars) based on current valuation of peaking capacity and common

Table 7

Net Benefits of CPP Pricing, Alternative Scenarios

Scenario	C0	C1	C2	C3
Per Customer Change in Benefits relative to Base				
Customer bill change (reduction)	$14.77	$14.77	$16.21	$27.77
% of summer base bill	3.1%	3.1%	3.3%	5.7%
Utility net revenues				
Utility costs	($14.77)	($14.77)	($16.21)	($27.77)
Utility revenues	($14.77)	($14.77)	($16.21)	($27.77)
Utility net revenues	$0.00	$0.00	($0.00)	($0.00)
Total	$14.77	$14.77	$16.21	$27.77
Aggregate Change in Benefits				
Change in Benefits Relative to Base	$590,906	$590,906	$648,600	$1,110,732
Avoided Generation Costs	$474,689	$474,689	$409,417	$701,129
Program Costs (annualized amount)	$1,321,833	$788,500	$788,500	$788,500
Total Net Benefits	-$374,261	$159,072	$596,611	$1,226,967
% of participants' summer base bills	-1.9%	0.8%	3.0%	6.3%

The leftmost column (Scenario C0) simply reproduces the Scenario C results from Table 6. Next to it, we assume that technical change reduces the cost of installed equipment by 50 percent. Total net benefits in Scenario C1 become modestly positive as a result. Increasing the number of hours of CP pricing from 29 to 43, and reducing the CP price in consequence from 51¢/kWh to 43¢ significantly increases net benefits to 3 percent of summer base bills (Scenario C2). Finally, assuming in Scenario C3 that customer response is, for some reason, as large as in Scenario A pushes net benefits even higher, to 6 percent of the summer base bills. Such response may occur because customer responses are somewhat "lumpy," with response increasing in steps rather than gradually, or because the pattern of prices includes more spikes without significantly raising average peak period non-CP prices.

Scenarios A through D were constructed as combinations of various historical summers. It may be asked what scenarios are likely to occur in the near future. Reserves conditions for the immediate future suggest outcomes closer to Scenarios A and B or even lower if the pattern and level of prices in 2001-04 should continue. However, not many days of prolonged heat could yield a scenario in the near term akin to Scenario C, at least in terms of its 29 hours of curtailment, if not its average non-CP price of 9¢/kWh. Outcomes such as Scenario D with 53 hours of curtailment and an expected CP price of 68¢ are likely some ways off. (However, it might be worth noting that PSE&G, albeit on the east coast, recently filed a CPP tariff with a summer CP price of 60¢/kWh. It may be that they expect some reasonable incidence of use at that price in the not too distant future.)

In summary, the CPP product's equipment costs present a very difficult cost barrier to surmount in securing the benefits of load modification from small customers. Although CPP is an appropriate product for IPL's customers, we cannot recommend that IPL pursue a CPP pilot immediately, as the prospect of immediate need is low and the costs of program startup are substantial.